DG Benefits Assessment Methodology

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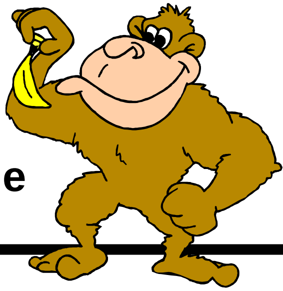
Assessing the Benefits of DG

- E3 has been working on DG benefits assessment since the late 1980s.
  - Evolution of approach and methodology
- Recent case studies:
  - Renewable DG Assessment Project (PIER-funded)
  - E2I/SCE Distribution Deferral Pilot (PIER ESI-funded R&D)
- Highlights of methodology shifts over time
- Ideas for R&D and development going forward

Evolution of DER Valuation



Stone Age

Today

Mid '80s Before E3
- Energy cost plus CT for generation capacity

Local Value (1989-1992) E3 'Landmark' Projects
- PG&E Kerman Study
- PG&E Delta Study

DR Concept (1992 - 1995) Marginal Cost & Integrated DG Planning
- DU Quantification Study
- Niagara Mohawk Remote Power
- Integrated G, T, and D Study
- Marginal Costs for DG

Expansion of DR Idea (1995 – 2000) Economic & Engineering Valuation
- Local Integrated Resource Planning
- Strategic Distribution Planning Study
- Profitability & Risk Assessment of T&D Expansion
- Transmission Wheeling & DR Applications

DR: A Valuable Resource (2000 - Today) Developing Tools for Integration and Planning
- NY DG Pilot Program
- BPA Non-Wires Alternatives
- Renewable DG Assessment
- E2I/SCE Deferral Value

DG Valuation Methodology

- The methodology we use today incorporates the following key attributes:
  - Focuses on valuing DG for the tangible benefits it can provide and facilitates transparency for payment of benefits
  - Is applicable to all non-wires alternatives including energy efficiency/demand side management, demand response, and energy storage
  - Is coordinated with engineering analyses
  - Is designed to value DG resources for the services they provide to the electrical system
  - Keeps direct and indirect costs and benefits separate to allow for a clearer interpretation of results

E2I/SCE Distribution Deferral Pilot

Project Overview

- E2I, SCE, and E3 collaborated to develop the Distribution Deferral Pilot program
- E3 contributed the deferral value estimation methodology to determine:

What should SCE pay for DG?

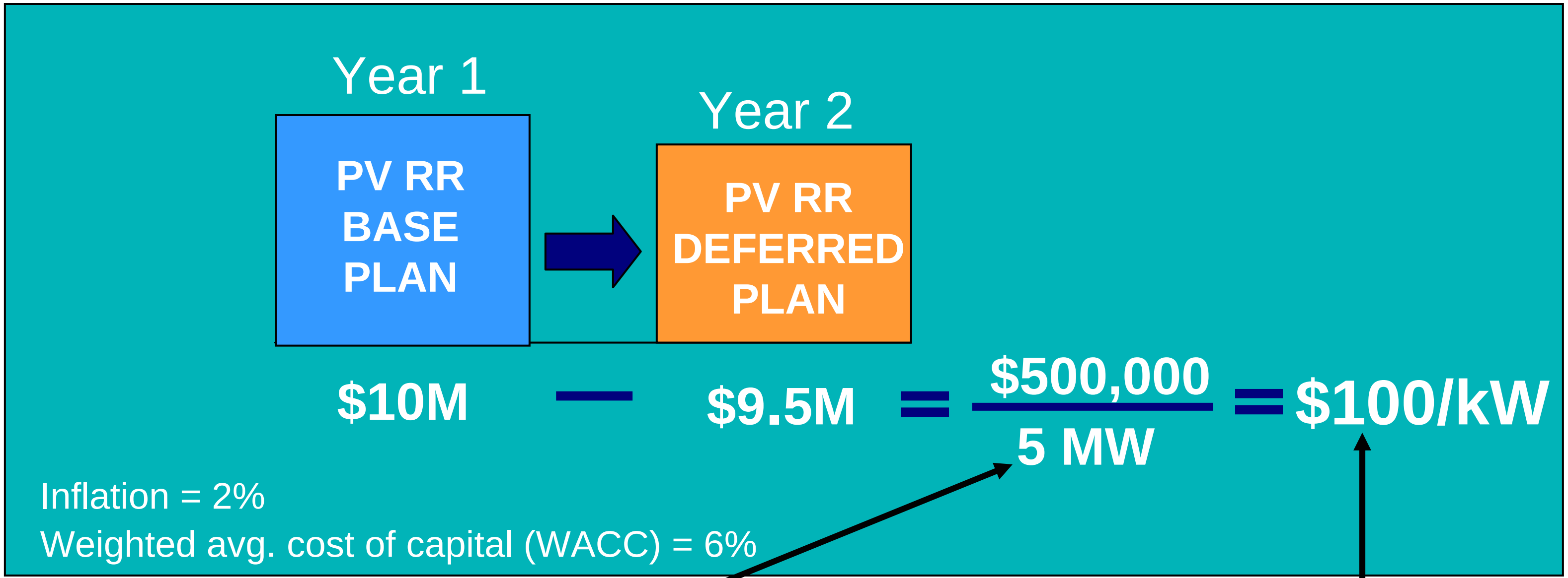
- E3 estimated the value DG capacity could provide for 5 SCE distribution projects
  - ‘value’ was measured by reduced cost to all SCE customers (i.e., SCE’s reduced ‘revenue requirement’)

Method for Computing DG Distribution Value

- For utilities, DG value = reduced customer cost
- Customer cost reflects utility expansion cost
  - expansion cost becomes part of the utility's ***revenue requirement*** (‘**RR**’) that it needs to recover from its customers
  - DG reduces expansion costs when it enables the utility to defer or avoid capacity expansion, while maintaining reliability
  - reducing expansion costs reduces utility RR, providing value to all utility customers in the form of lower costs
- Change in RR computed on ‘present worth’ basis
- Value of DG to the utility = avoided capital cost, adjusted for future year cost increases (inflation)

The Present Worth Method

PW Savings = (PVRR Base Plan – PVRR Deferred Plan) / Annual Load Reduction Needed to Defer



5 MW of DG is needed each year to defer expansion: less than 5 MW will not defer, so has zero deferral value.

$100/kW is the *Deferral Value* to the utility, and the maximum incentive payment the utility could pay for an alternative to defer its base expansion plan.

Example Analysis for Project "A"

Example: Project A
Summary Characteristics

- Replace/upgrade transformer to serve new commercial & residential load, & replace existing transformer for maintenance
- Project Direct Budget: $1,040,000
- Project Revenue Requirement: $1,352,000
- Capacity Addition with Project A: 10,000kVA (10 MVA)
- Expanded distribution capacity needed <100 hours/year
- Capacity needed in the area increases over time

Cumulative Capacity (kVA) required by year to defer project				
2003	**2004**	**2005**	**2006**	**2007**
290	580	880	1170	1470

Example: Project A
Calculating Deferral Value Using PW Method

Value for Year One

PW Savings (Deferral Value) = <u>(PVRR Base Plan – PVRR Deferred Plan)</u>
Annual Load Reduction Needed to Defer

Deferral Value = $1,352,000 - $1,262,000 = $90,000

$$= \frac{\$90{,}000}{290\ \text{kVA}} = \$311/\ \text{kVA}$$

Basic Assumptions:

- WACC = 9.3%
- Inflation = 2%
- RR Scaler = 1.3

Example: Project A
Calculating the Deferral Value Using PW Method

Value for Years Two & Three

Deferral Value = $\dfrac{\textbf{(PVRR Base Plan – PVRR Deferred Plan)}}{\textbf{Cumulative Load Reduction Needed to Defer}}$

Year 2

Deferral Value = \$1,262,000 - \$1,178,000 = $\dfrac{\$84{,}000}{580\text{ kW}}$ = \$145/ kVA-yr

Year 3

Deferral Value = \$1,178,000 - \$1,099,000 = $\dfrac{\$79{,}000}{880\text{ kW}}$ = \$89/ kVA-yr

Basic Assumptions:
- WACC = 9.3%
- Inflation = 2%
- RR Scaler = 1.3

Example: Project A
Value of a Three-Year Deferral

PRESENT VALUE OF THREE-YEAR SAVINGS STREAM

Year one	$90,000 / 290 kVA	= $311/ kVA
Year two	$84,000 / 580 kVA	= $145/ kVA
Year three	$79,000 / 880 kVA	= $89/ kVA
Present Value	$253,000 / 880 kVA	= $265/kVA

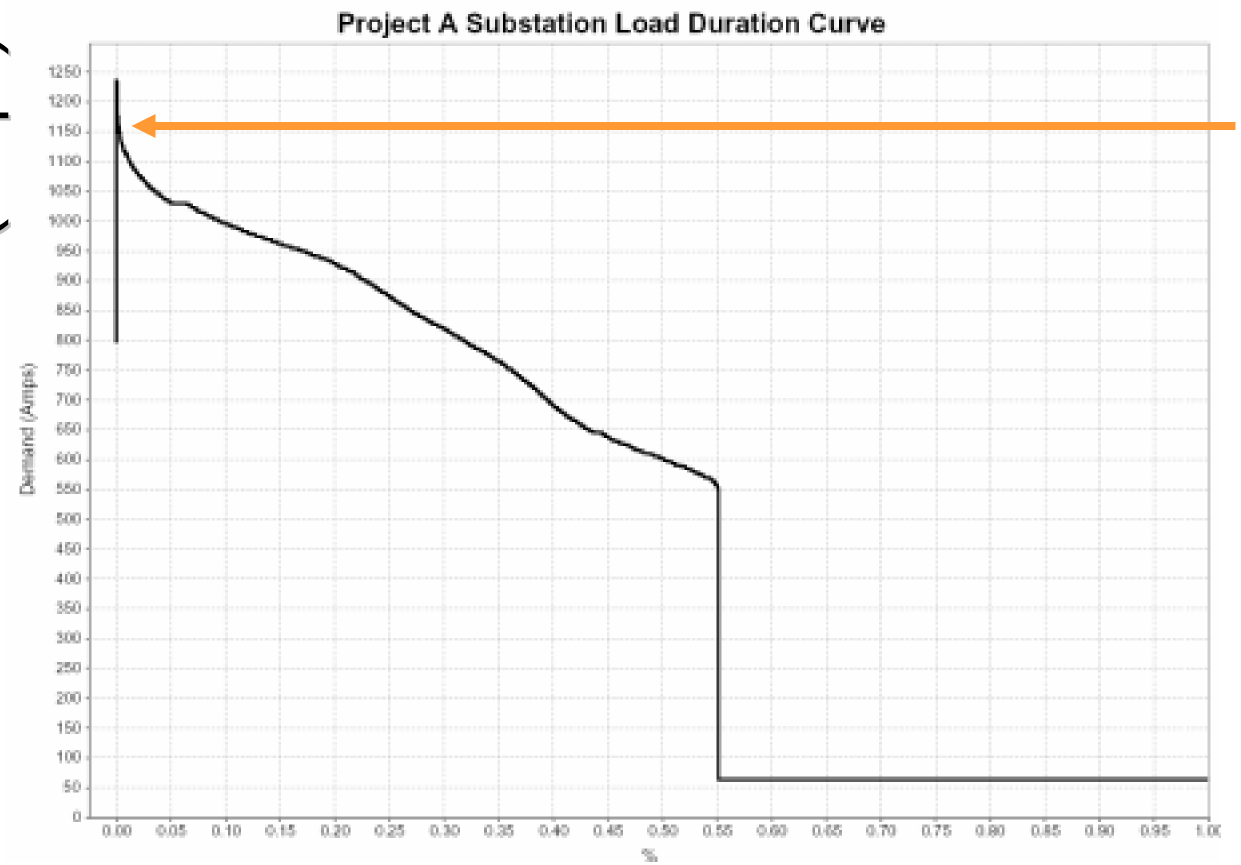
Ratepayers better off as long as DG payments are less than $253,000 ($265/kVA for 880kVA)

Basic Assumption:
WACC = 9.3%

Example: Project A
Operational Requirements

DG is required to reduce peak loads

Local Area Demand (Amps)



Percent of Hours (Sorted High to Low)

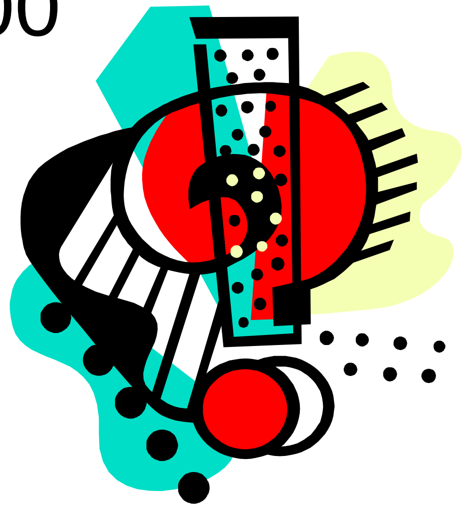
DG operates during highest load hours

Usually the hottest summer days

About 100 hours in this area

What does this all mean?

- Area “A” DG is worth roughly \$311/kVA-yr in year 1
- Value falls off quickly to \$89/kVA-yr within 3 years
- 3-year contract for 880kVA is worth about \$265/kVA over 3 years, or \$253,000
- Keys to capturing this value are:
  - *location*
  - *dispatch*
  - *coordination* with distribution planning



Summary of Projects Evaluated

Project **ID**	Project **Cost** ($000)	Capacity **Addition** (kVA)	**Reason for Project**
A	**$1,040**	**10,000**	Replace/upgrade transformer to serve new commercial & residential load and replace existing transformer due to maintenance requirements.
B	**$1,747**	**34,000**	Add transformer to serve new residential and commercial load.
C	**$1,695**	**28,000**	Add transformer to provide capability for (N-1) loss of existing transformer banks.
D	**$600**	**0**	Add circuit to serve new residential and customer load in the area.
F	**$840**	**0**	Add circuit to balance circuit loading and facilitate load transfer to adjacent Sub.

Projects include a range of new transformer and circuit additions ($600,000 to $1,747,000)

Summary of Results for 5 DPAs

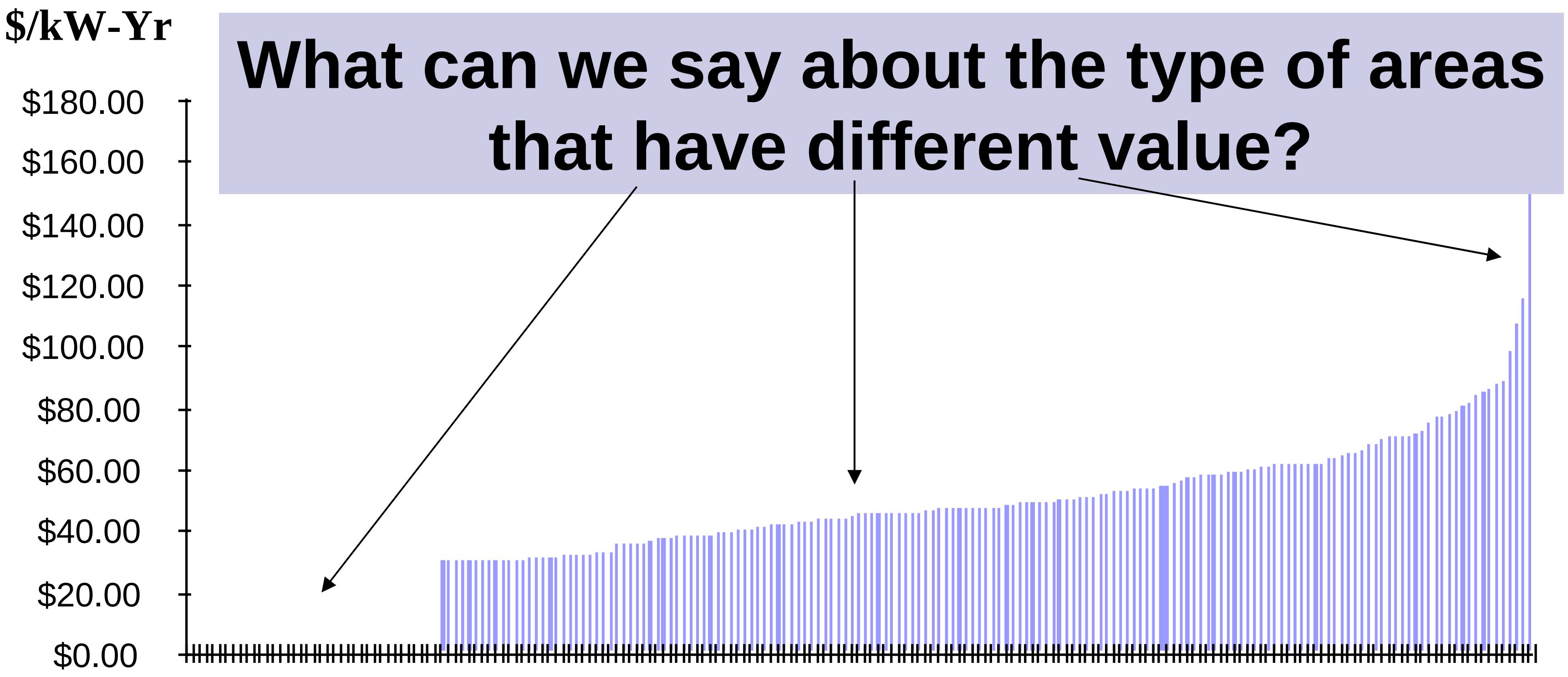
- Range of 'Best Areas' shows significant variation in distibution value.

Change in Revenue Requirement ($/kVA) Duration of Contract (2003 Start)					
Project ID	1 Year	2 Year	3 Year	4 Year	5 Year
A	$ 311	$ 289	$ 265	$ 247	$ 230
B	$ 147	$ 137	$ 95	$ 42	$ 36
C	$ 90	$ 93	$ 90	$ 85	$ 80
D	$ 48	$ 49	$ 48	$ 45	$ 43
F	$ 347	$ 644	$ 897	$ 26	$ 21

Acculmative Capacity (MVA) required by year to defer project					
Project ID	2003	2004	2005	2006	2007
A	0.29	0.58	0.88	1.17	1.47
B	1.03	2.06	4.12	11.47	15.88
C	1.63	2.94	4.24	5.55	6.85
D	1.09	1.96	2.83	3.7	4.57
F	0.21	0.21	0.21	8.91	13.26

Another Example from the Past ~1994

Variation of Distribution Value over 200+ Areas



Present Worth Marginal Capacity Costs by Distribution Area – 1994 PG&E Example

Renewable DG Assessment Project

RDG Assessment - Background

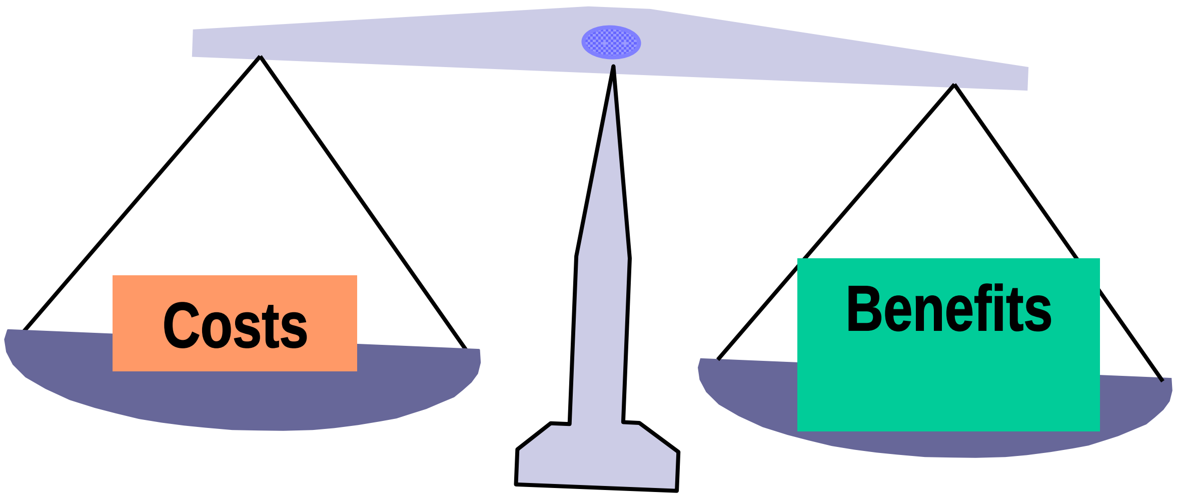
- The Renewable DG Assessment (RDG) project developed a ***joint***- engineering and economic approach for utility evaluation of RDG.
- Four California municipal utilities participated:
  - Alameda Power and Telecom
  - City of Palo Alto Utilities
  - Sacramento Municipal Utility District
  - San Francisco Public Utility Commission – Hetch Hetchy
- Key objectives were identified as:
  - Analyze local system impacts and benefits that accrue directly to a municipal utility in a localized network
  - Expand the evaluation methodology to evaluate the impacts on local system reliability, including value to both the customers and the utility
  - Incorporate load growth and generator system performance uncertainty as reflected in weather assumptions

Key Results from 4 Assessments

- Difficult to find cost-effective RDG on a net direct-benefit basis
  - Avoided costs (benefits) are too low
  - RDG capital costs are too high
- Indirect benefit value must be high to make up for ‘gap’ in cost-effectiveness
- Cost-effective technologies tended to be larger CHP applications
- If sited in the <u>best</u> location RDG can provide substantial benefits to distribution systems with regard to:
  - Capacity release
  - Peak loss reduction

Economic Screening

- Economic screening analysis is based on lifecycle benefits from each stakeholder perspective
- Not a financial pro-forma model



Direct Benefits of Renewable DG

Benefit Category	**Data Source/Analysis**
Avoided Generation Costs	■ Internal market price forecast ■ Publicly available forecast of electricity or gas ■ E3 used the CEC natural gas price forecast as the foundation for our electricity price forecast
Avoided Distribution Costs	■ Marginal cost analysis of deferrable planned distribution investments
Avoided Transmission Costs	■ Marginal cost analysis of current and expected future transmission costs under MD02
Improved Reliability	■ Value of Service (VOS) analysis based upon calculated Energy Exceeding Normal (EEN)
Bill Savings for Customer	■ Rate analysis for each utility based on technology type and operation characteristics

Direct Costs of Renewable DG

Cost Category	Data Source/Analysis
Capital Costs	■ National Renewable Energy Laboratory Technology Characterizations ■ Direct Vendor Quotes
Operations & Maintenance Costs	■ National Renewable Energy Laboratory Technology Characterizations ■ Direct Vendor Quotes
Program Administration Costs	■ Vendor Estimates
Revenue Loss for Utility	■ Rate analysis for each utility based on technology type and operation characteristics

Assessment of the ‘Shortfall’ Between Benefits & Costs

<u>DIRECT BENEFITS</u>*:*

- Energy Generation
- Transmission Savings
- Distribution Capacity Savings

Less

<u>COSTS</u>:

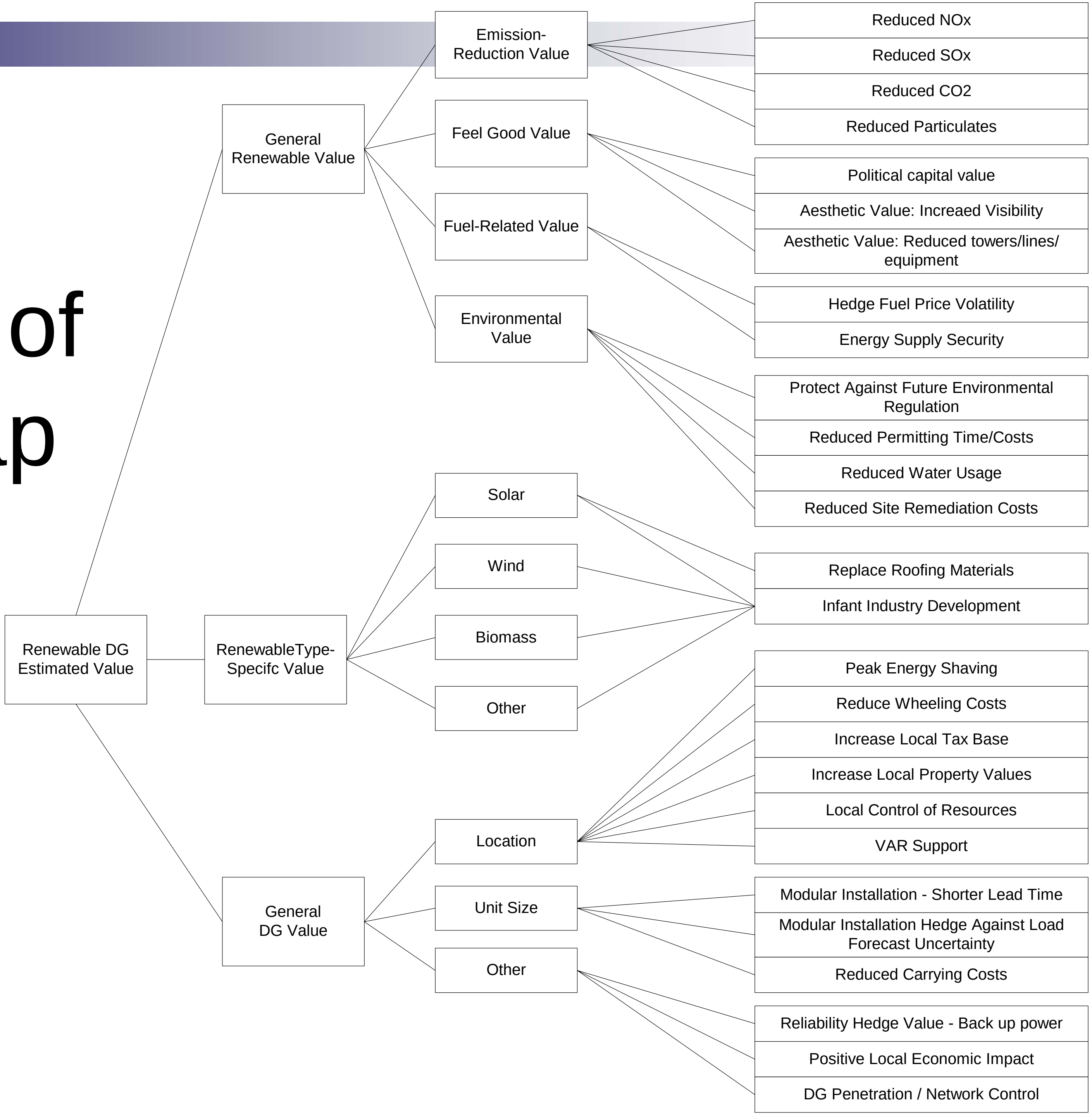
- Capital Costs
- O&M Costs
- Program Administration Costs

Equals

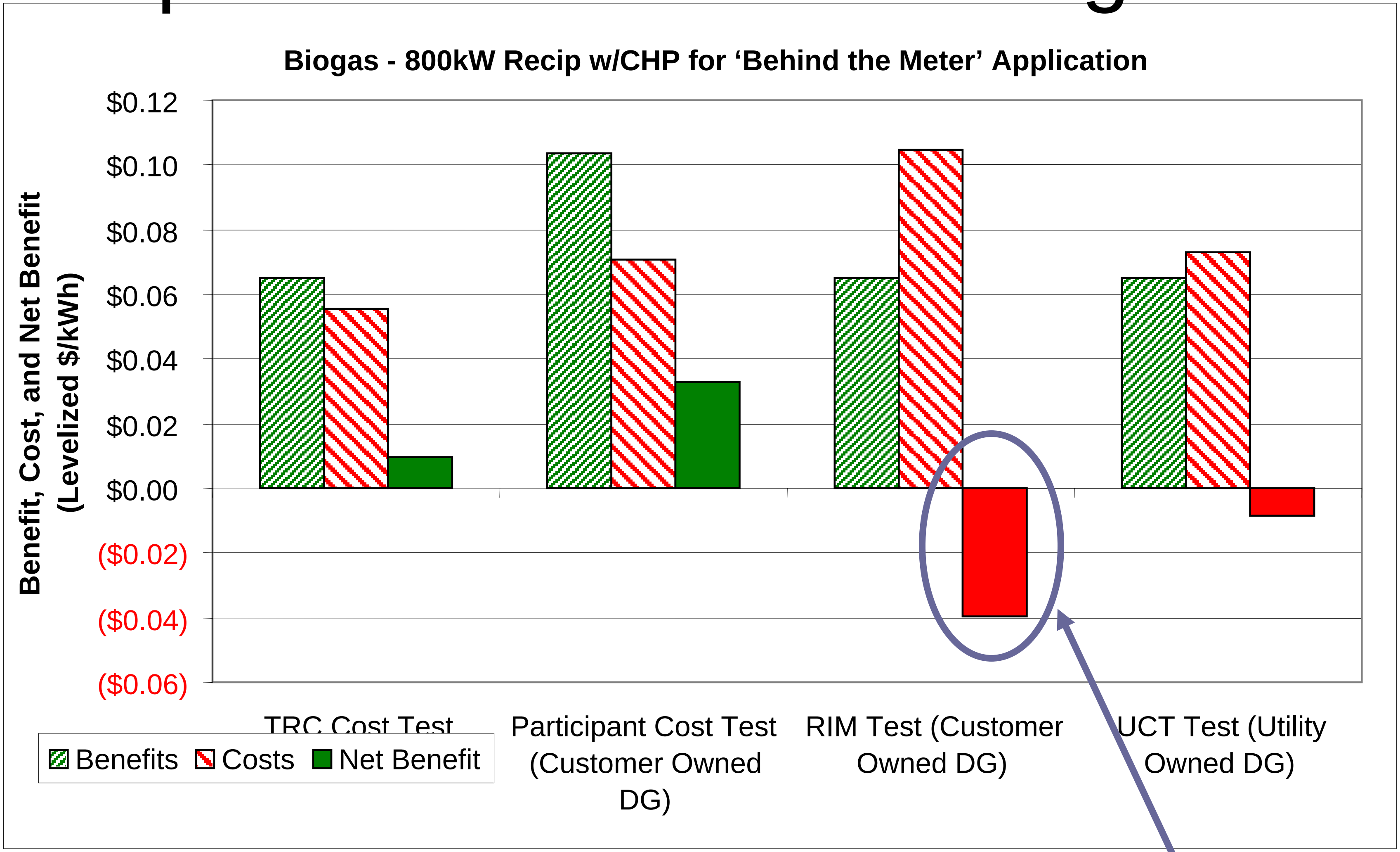
SHORTFALL

“INDIRECT” BENEFITS MAY BE GREATER THAN THE SHORTFALL

Indirect Benefits of RDG Map



Example: Economic Screening Results



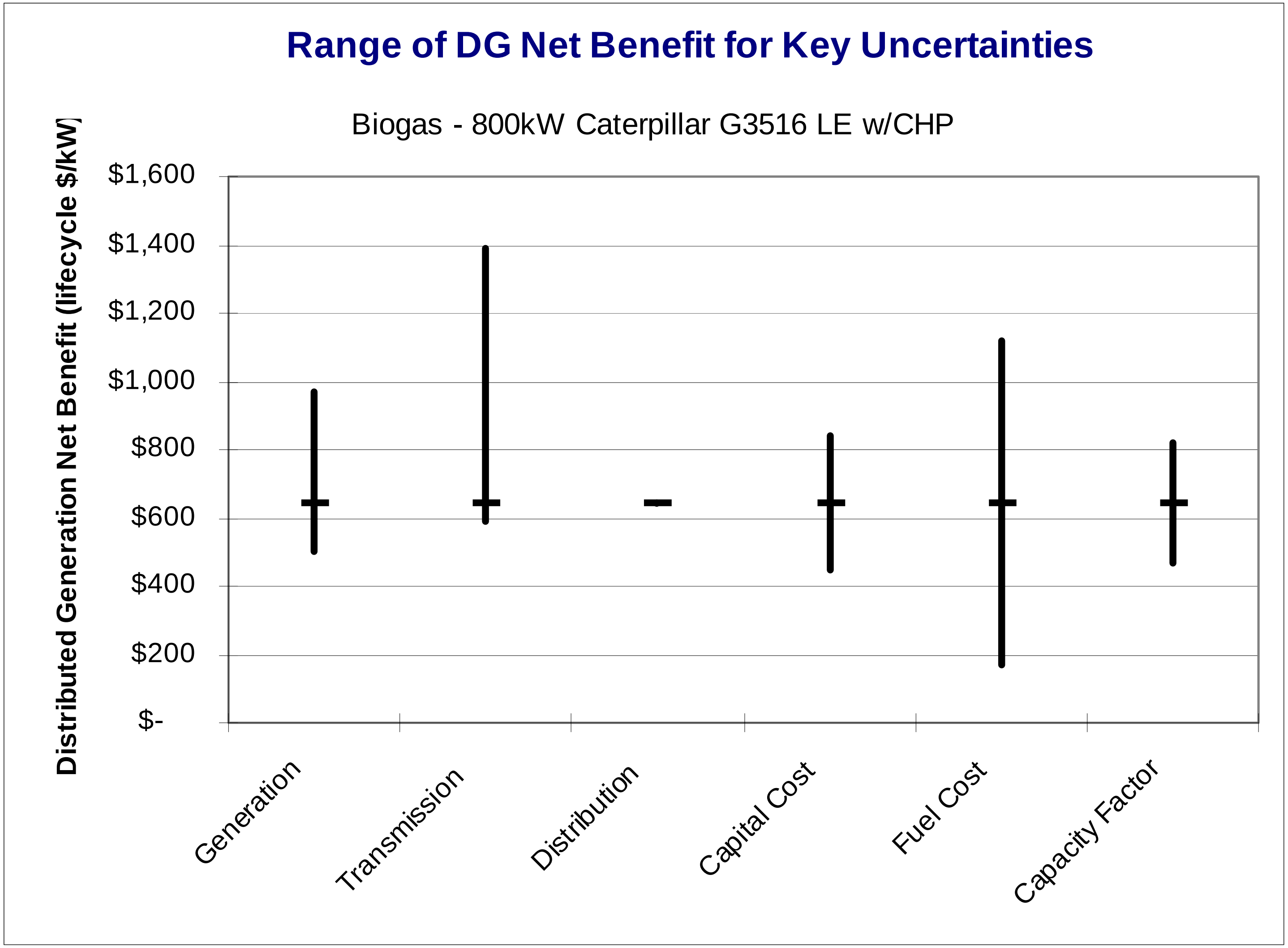
City of Palo Alto Utilities: 8-2004 Analysis

Economic "Shortfall" for Ratepayers

Uncertainty Analysis

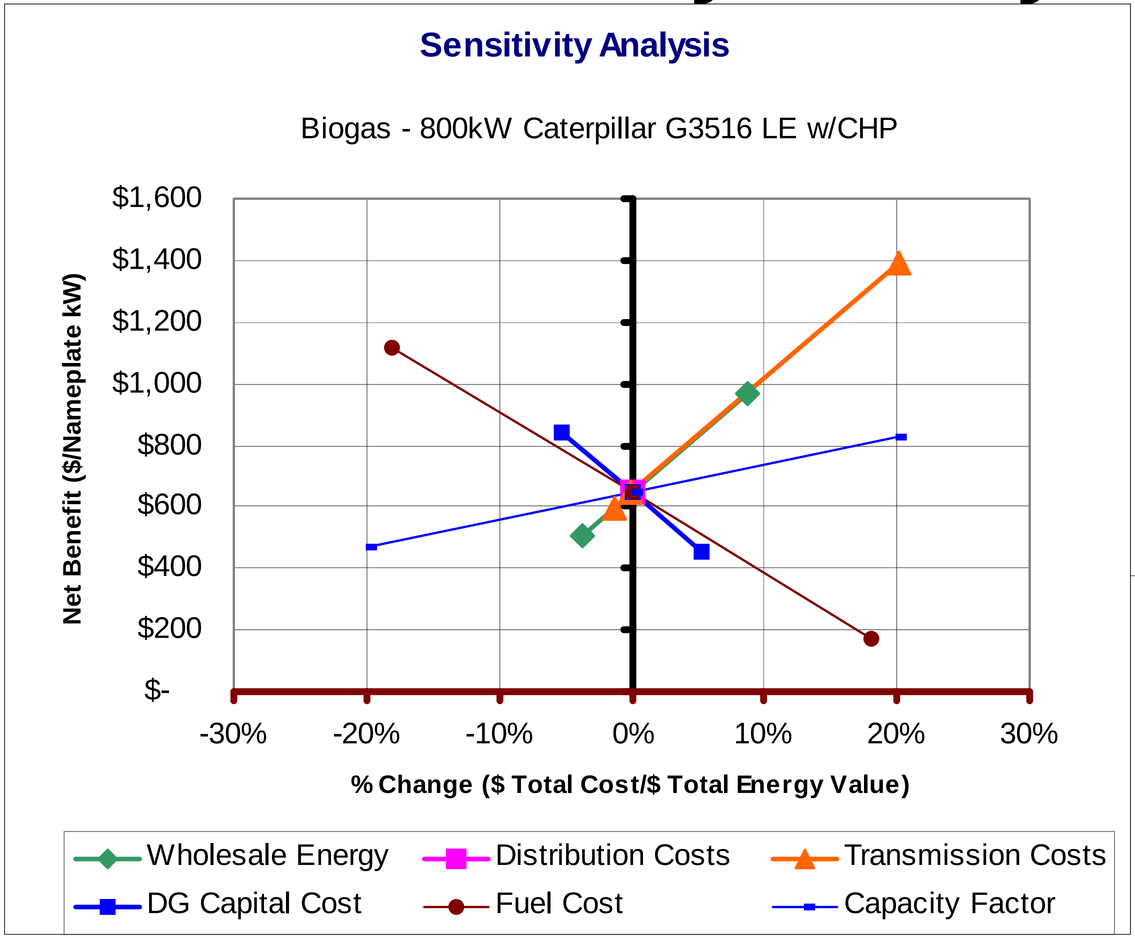
- Economic screening analysis results can change dramatically due to uncertainty
- Particularly true for intermittent resources
- Results were most sensitive to input changes for:
  - Fuel costs
  - Wholesale energy (generation) costs
  - Capital costs (for solar PV)
  - Capacity factor

Testing Sensitivity of Results for Uncertainty



City of Palo Alto Utilities: 8-2004 Analysis

Detailed Sensitivity Analysis Result

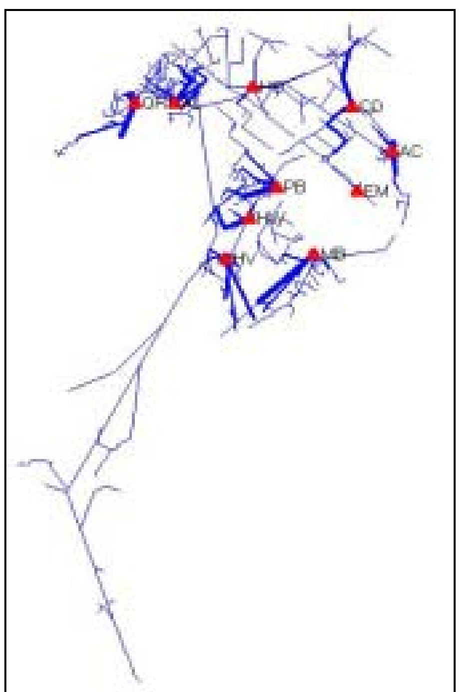


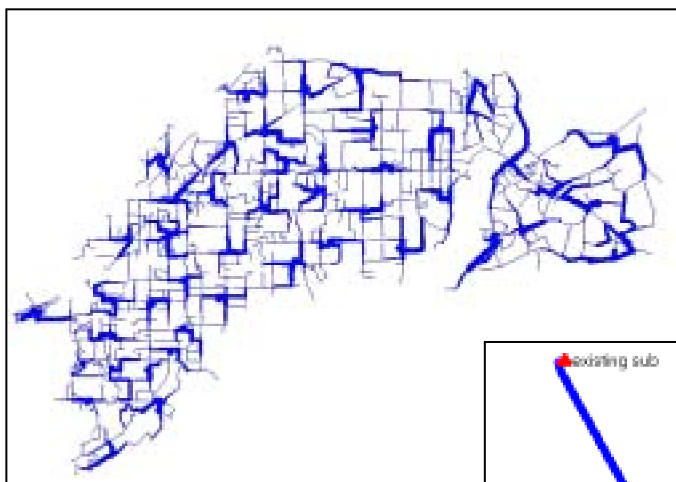
City of Palo Alto Utilities: 8-2004 Analysis

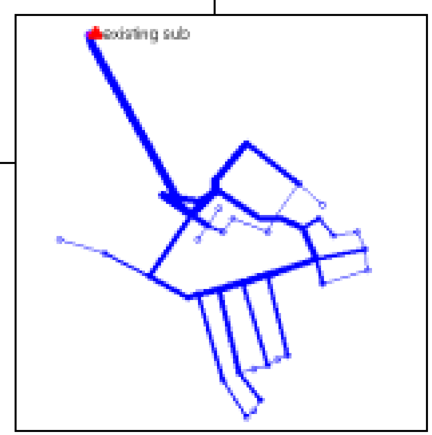
The 800 kW biogas generator with CHP (combined heat and power) is cost-effective under the TRC test within nearly the full range of sensitivities tested

Engineering Analysis

- Identify timing and location of future capacity constraints
- Typical model is a ‘snap shot’ of peak hour of the year
- Hourly load-flow capability creates link to planning decisions (e.g. DG dispatch requirements)

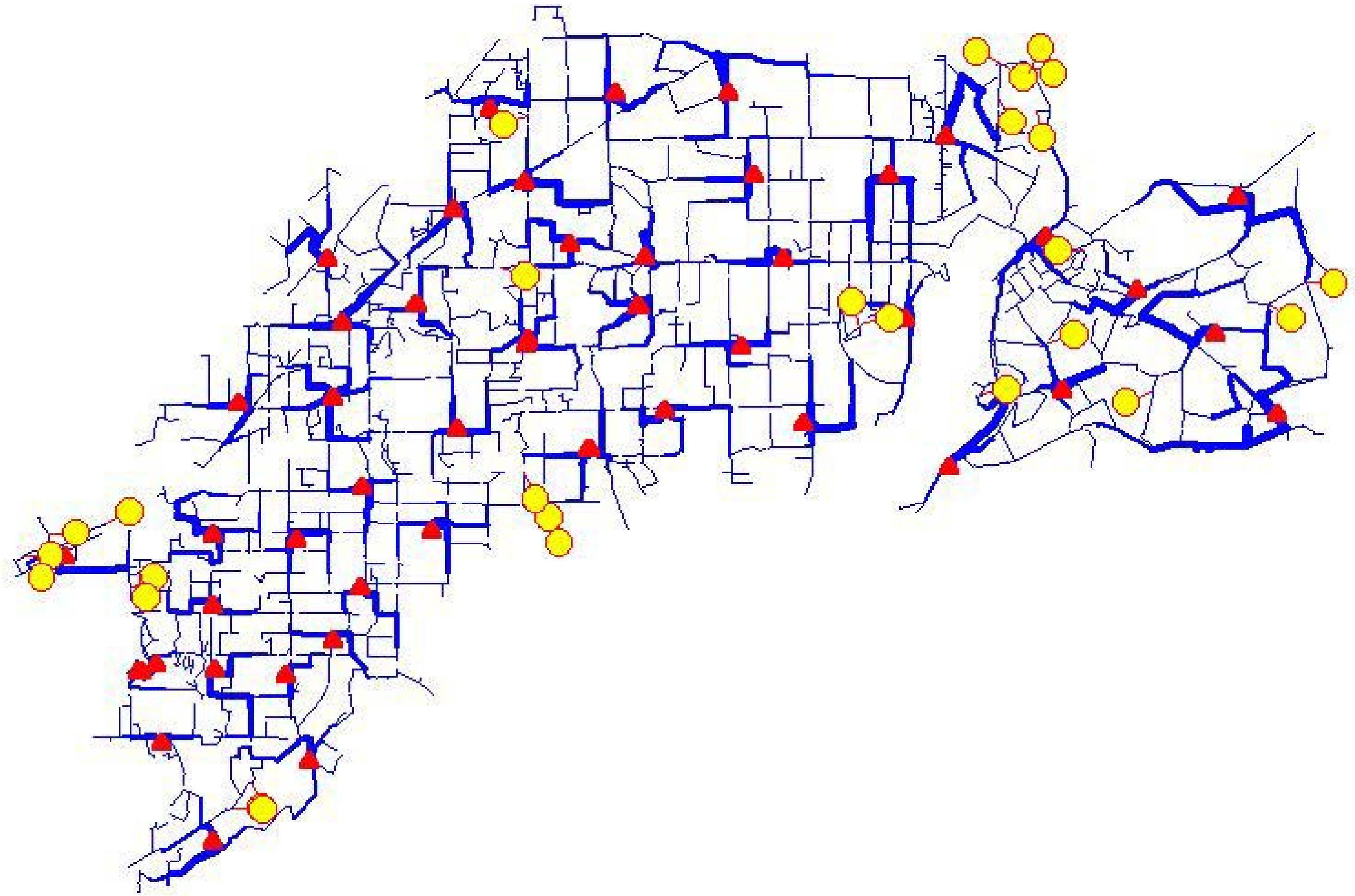






Siting Analysis

SMUD Example: 13.5 MW DG optimally sited for released capacity



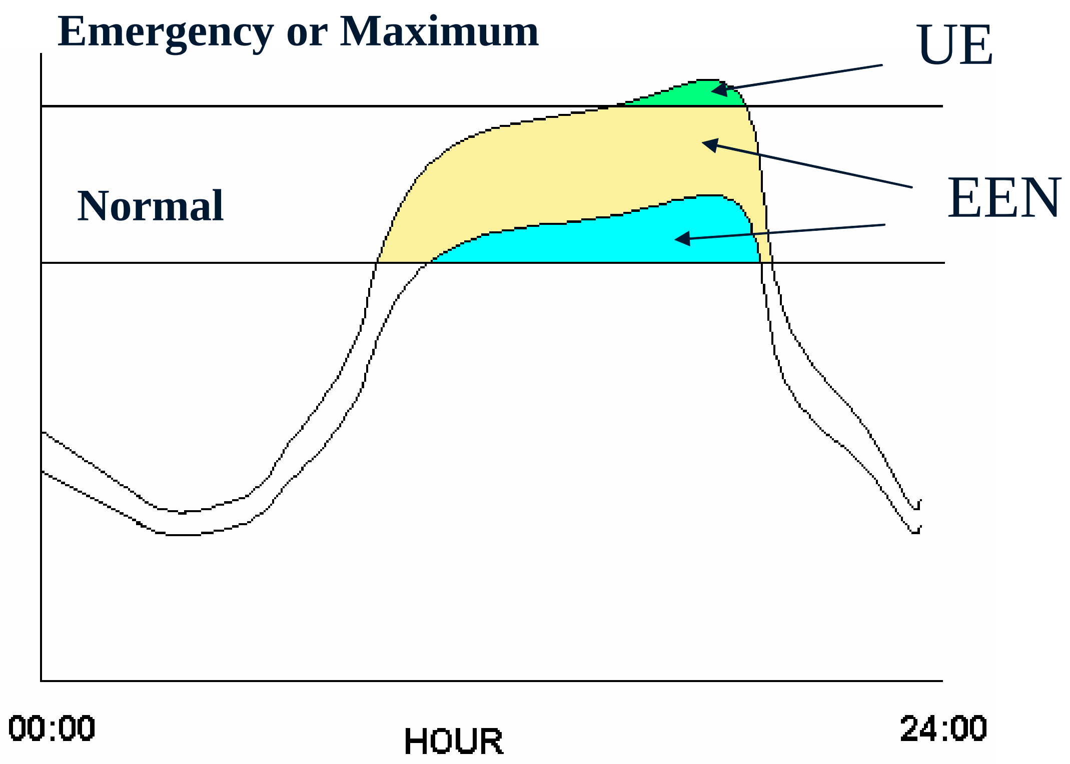
Operational Feasibility

- Voltage Regulation Screen
  - Using a voltage change threshold of 5%
- Overcurrent Protection Screen
  - Typically evaluated with a fault current change threshold of 50%

Darker colors indicate greater changes in fault current with RDG installed

Reliability Analysis-Basic Concept

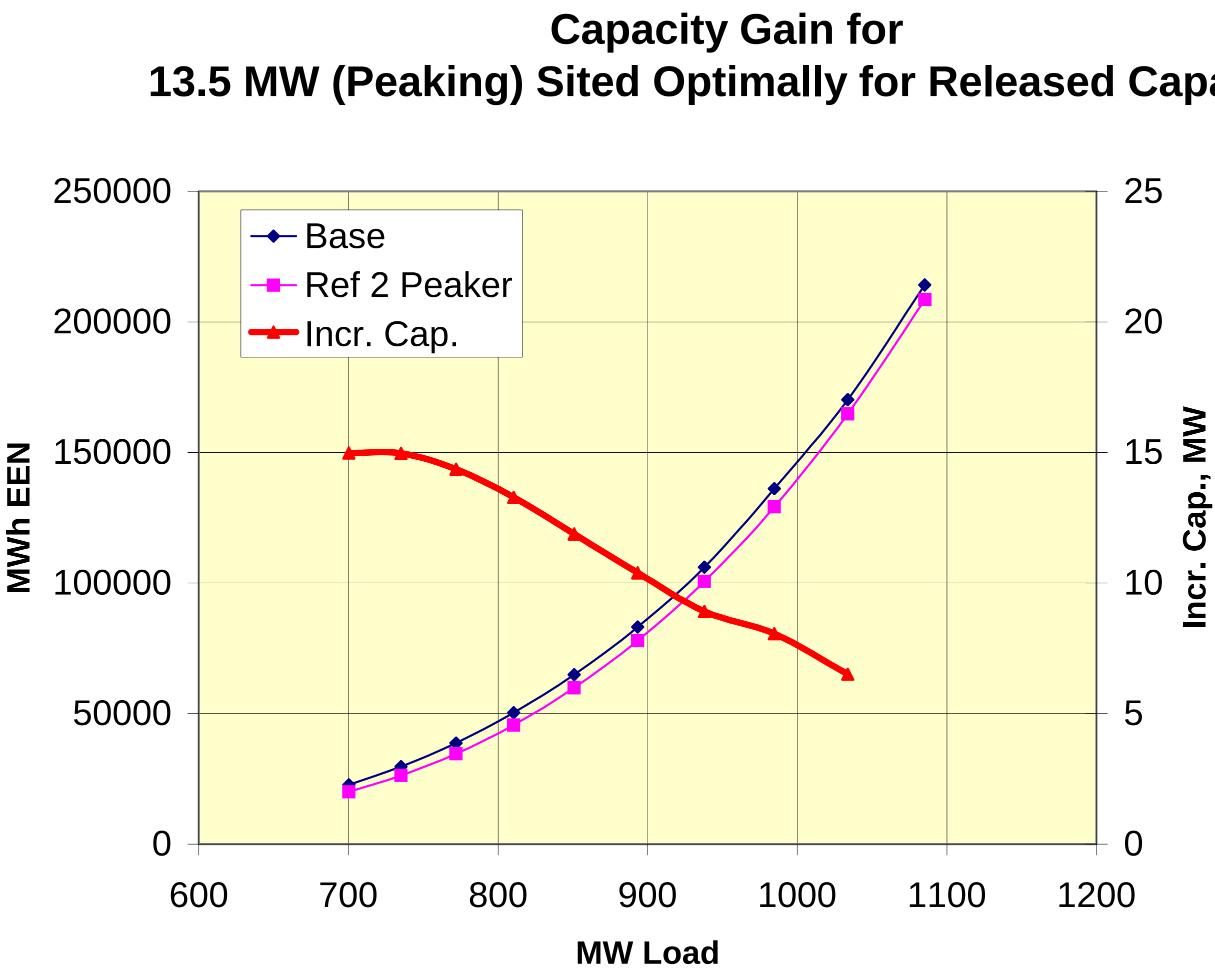
- Hourly load-flow example for a peak day



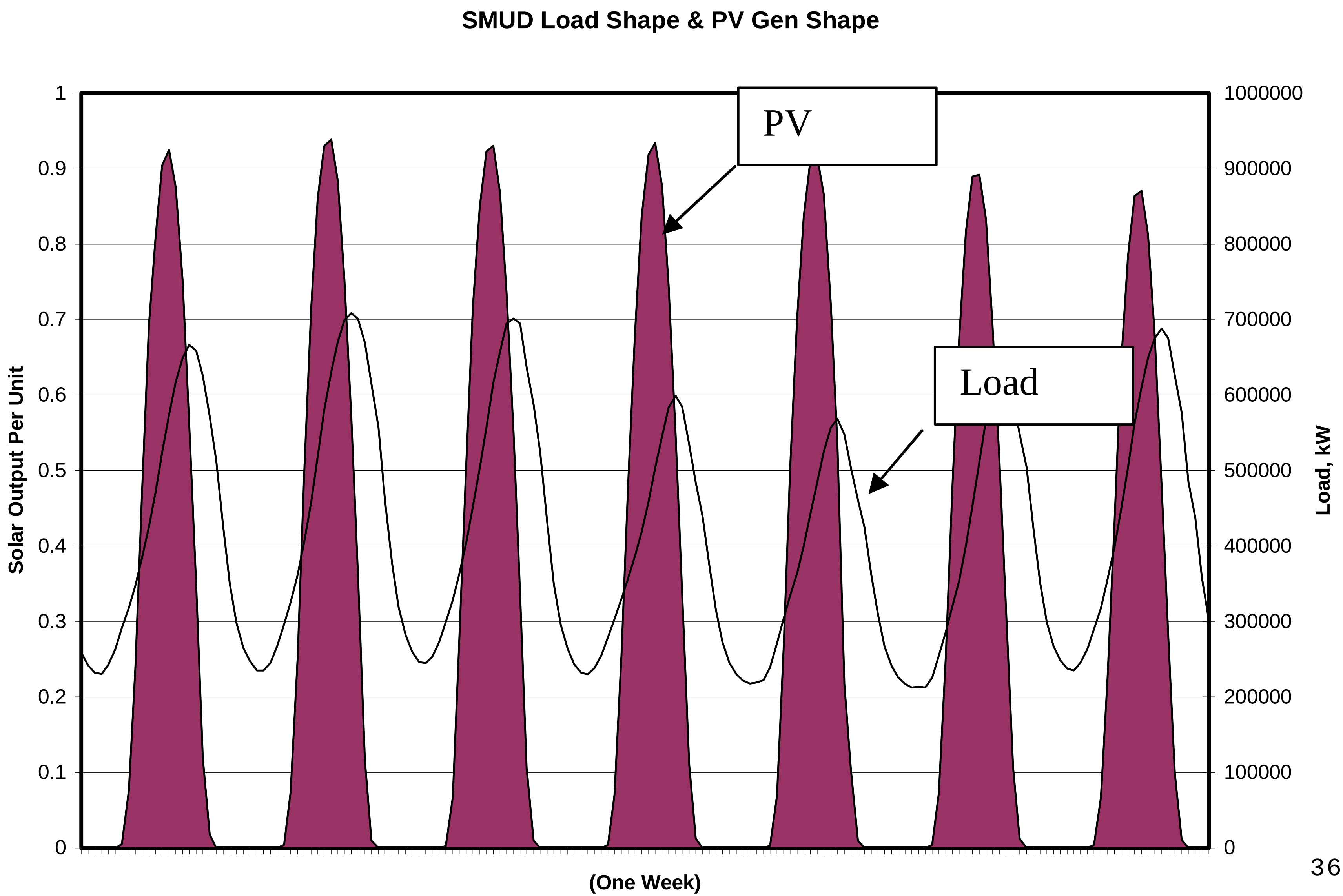
UE = Unserved Energy, EEN = Energy Exceeding Normal

- Calculate UE and EEN with renewable DG operating
- Allows quantification and costing of reliability benefits

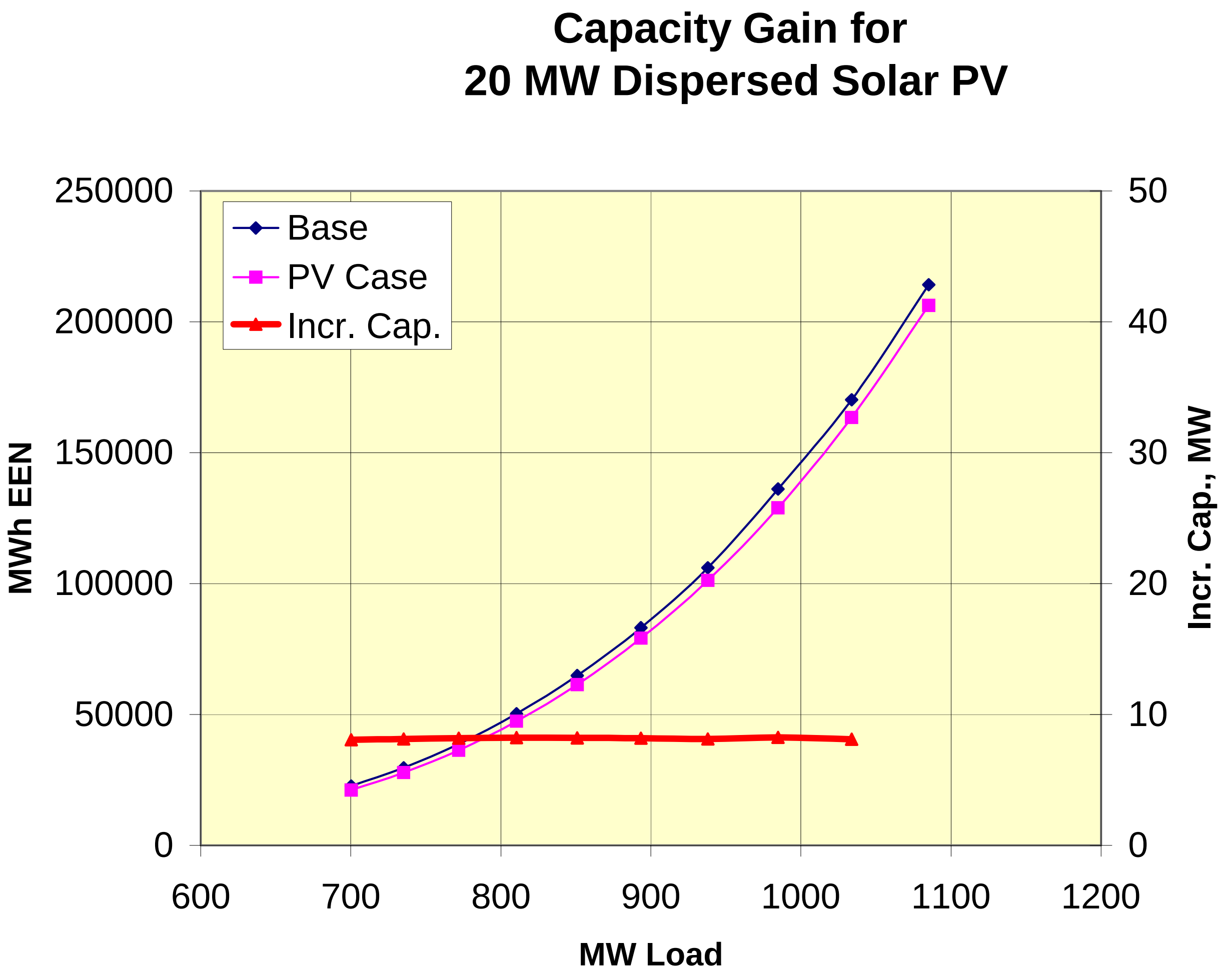
EEN computed for 13.5 MW of DG sited in 500 kW units for maximum benefit to released capacity (peaking)



SMUD Load Shape & PV Generation Shape



Capacity gain with respect to EEN for 20 MW of solar PV



Other Reliability Approaches

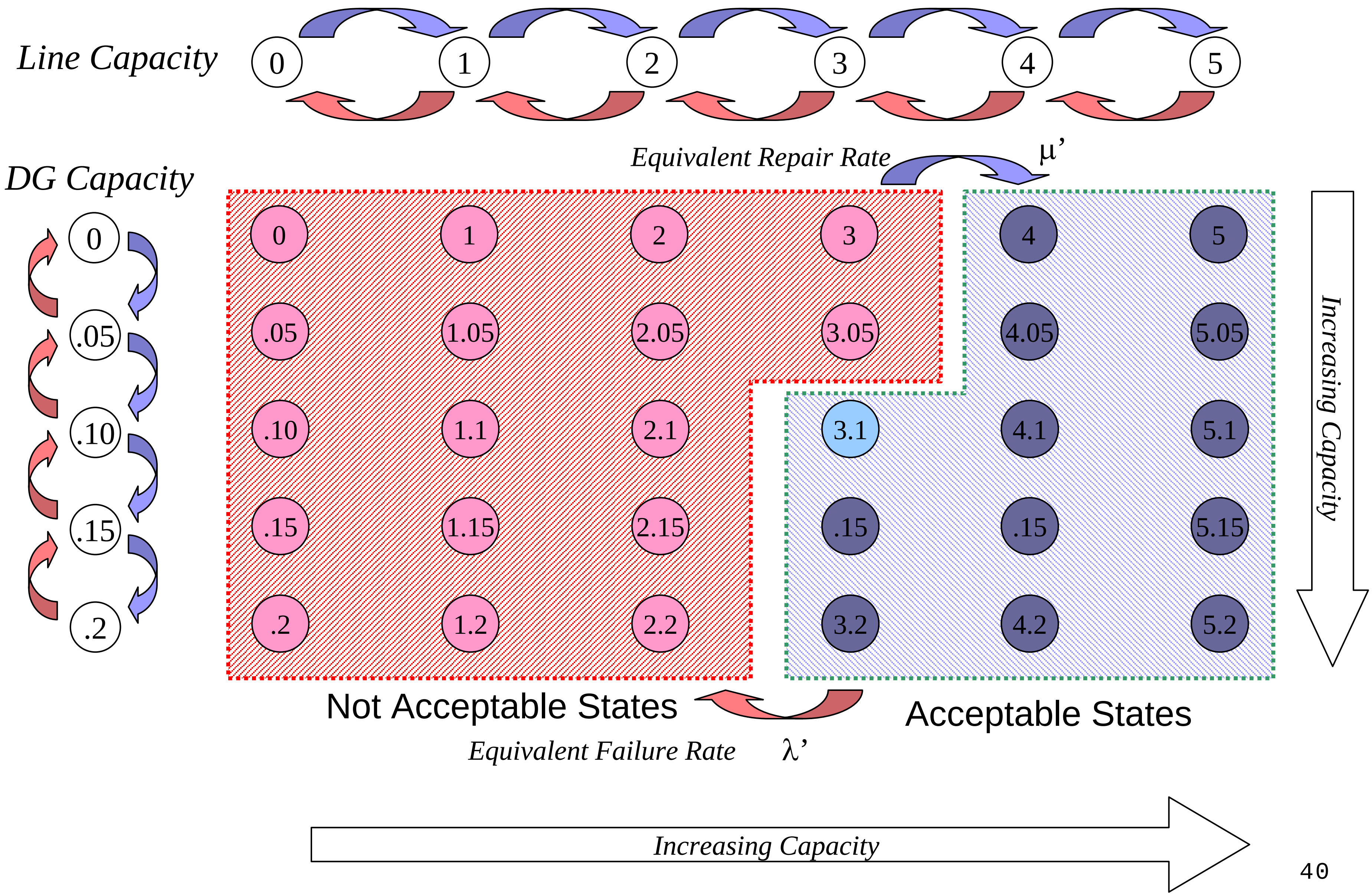
- Planning with Distributed Resources
  - N-1 Criteria is not appropriate for planning with Distributed Energy Resources

- Equivalent Reliability
  - Redundant DER Units
  - Physical Assurance

The Equivalent Reliability Methodology

- Use the load forecast to set the required capacity to serve the study area (e.g. 500 MW)
- Compute probability that the integrated plan provides ‘equivalent’ reliability to the traditional system
  - Estimate the availability of each transmission path and its load carrying capability
  - Define the reliability of the combined resources to serve the area (e.g. 99.999%)
  - Estimate the availability of each individual resource (e.g. DG is 95%, Demand Response is 75%)
  - Use a Markov chain model to determine the states that provide enough capability and their probability.
- Compute the nameplate capacity of additional resources required to match ‘equivalent’ reliability of traditional solution based on existing engineering criteria

Markov Approach to Estimating Reliability



Use of Reliability in DG Bidding

Total Number of Generators	Number of "Firm" Generators	Number of Largest Generators that are "Non-Firm" (Step 2)	Number of Smallest Generators that are "Non-Firm" (Step 4)
1	0	1	0
2	0	1	1
3	0	2	1
4	1	2	1
5	2	2	1
6	3	2	1
7	3	2	2
8	4	2	2
9	5	2	2
10	6	2	2
11	6	3	2
12	7	3	2
13	8	3	2
14	9	3	2
15	10	3	2
16	11	3	2
17	11	3	3
18	12	3	3
19	13	3	3
20	14	3	3
20 or more		3	3

Start with nameplate of all generators in area e.g. 10 1MW DGs

Look up the number of generators

Subtract largest generators e.g. 10-2 = 8MW

Subtract smallest generators e.g. 8-2 = 6MW

Result is the 'firm' capacity of bid e.g. 6MW

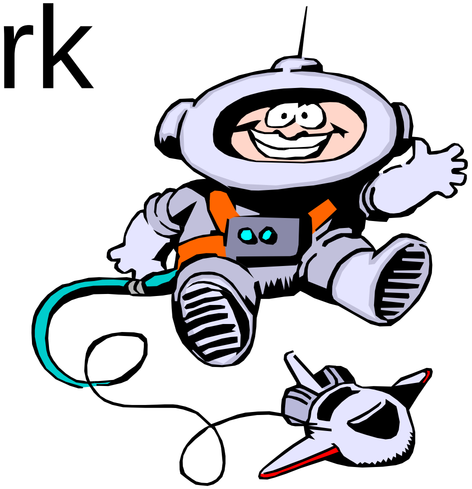
Based on 95% availability: 97% table available with proof of lower FOR

Example Results with Reduncancy

- Required Installed Capacity for ‘Equivalent Reliability’

	Year Firm Capacity Shortfall		
kW/unit	2001 4MW	2002 14MW	2003 19MW
30	4.38 MW, 110%	14.46 MW, 103%	19.59 MW, 103%
250	5 MW, 125%	16 MW, 114%	21.25 MW, 112%
500	5.5 MW, 138%	16.5 MW, 118%	22 MW, 116%
1000	6 MW, 150%	18 MW, 129%	23 MW, 121%
2000	8 MW, 200%	20 MW, 143%	26 MW, 137%
5000	15 MW, 375%	25 MW, 179%	30 MW, 158%

Ideas for Further DG Work



Focus on Implementation

- **Workable Regulatory & Business Models**
  - **Payment for Services Based on Value**
  - **Win-Win-Win**
- **Real-world Projects to Demonstrate**
  - **Engineering**
  - **Metrics**
  - **Business Models**
- **Metrics to Standardize Across Resources**